A new 'capture ready' power plant project in Saskatchewan

Max Ball, Manager Sustainable Supply Development
Bob Stobbs, Project Leader
Larry Ward, Senior Engineer Internal Supply Options
SaskPower, Regina, Saskatchewan, Canada

Jon Gibbins,
Energy Technology for Sustainable Development Group
Mechanical Engineering Department, Imperial College London

Malcolm Wilson, Director Energy & Environment
University Regina, Regina, Saskatchewan, Canada

Abstract

SaskPower is the principal supplier of electricity in Saskatchewan, Canada, operating 15 generating facilities, with an installed capacity of about 3 GW. Fossil generation is used to supply the majority of the electricity produced by SaskPower, with the remainder coming from hydroelectric and wind facilities. A new fossil plant with between 350 and 450 MW output may be required in the next decade and, because of expectations of high natural gas prices, there is serious interest in using local lignite as the fuel. Currently gasification technology options for lignite are limited so combustion plants, either pulverised coal or fluidised bed, with a supercritical steam cycle are being examined. No firm requirement to capture CO_2 emissions from the plant can be anticipated but, since Canada is already a signatory to the Kyoto Treaty, future CO_2 capture options are needed to avoid the risk of it becoming a stranded asset – it needs to be 'capture ready'. Preliminary analysis has identified both the loss in plant output and the capital cost of the capture equipment as major factors in overall capture and storage costs. The object of the current feasibility study is to examine how both of these can be reduced, by appropriate design and layout of the 'capture ready' plant. It is anticipated that post-combustion capture will be the principal focus, but accommodating this in 'capture ready' designs is complicated by the lack of demonstration plants for current technologies and the prospect of technology improvements before capture is actually fitted. Fortunately the first indications are that, due to the inherent flexibility of steam turbine plant, a range of future options can probably be allowed for at minimal additional cost.

Introduction

Saskatchewan Power Corporation ("SaskPower") is a Crown owned, vertically integrated utility having primary responsibility for generation, transmission and distribution of electricity within the Province of Saskatchewan. SaskPower's generating capacity is comprised of a mix of coal, hydro, natural gas, wind and distributed generation. In addition, SaskPower maintains all transmission and distribution lines in the province.

As part of ongoing supply planning it is anticipated that new major generating facilities will need to be in operation by 2013. This falls immediately after the first implementation phase of the Kyoto Accord, of which Canada is a signature. Selection of an option is therefore impacted by the risks associated with potential GHG regulations that may be implemented by the Canadian government.

To address some of these concerns SaskPower is conducting studies to determine potential options for mitigating GHG emission. Post combustion capture appears to be a leading candidate. Preliminary analysis has identified both the loss in plant output and the capital cost of the capture equipment as major factors in overall capture and storage costs. The object of the current feasibility study is to examine how both of these can be reduced, by appropriate design and layout of the 'capture ready' plant.

The scope of the work being undertaken is at a pre feasibility level of costing, that is cost estimates of plus or minus 30%. Based on system requirements the coal fired option is anticipated to be in the 350 to 450MW size range (before capture is added).

CO_2 storage for the power plant may be achieved by use of CO_2 for enhanced oil recovery (EOR) or injection in an aquifer adjacent to the plant, depending on the prevailing economics and regulations when capture is added. Although detailed geological site assessments and the appropriate authorization procedure would be required before any CO_2 storage option was used, it appears likely that sufficient storage capacity will be available for the project as envisaged.

Goals of Work

The primary goals of the work being done are:

(a) To develop basic engineering parameters for a supercritical coal plant alternatives, using Saskatchewan lignite as the fuel source.

(b) To provide sufficient information for SaskPower to evaluate technical and economic differences between CFB and pulverized coal plant.

(c) To evaluate the technical requirements and economic impact of making provision for future CO_2 capture using an amine capture process and

(d) To provide preliminary design concepts and cost estimates at a sufficient level allow to SaskPower to make decisions on next supply options for which full feasibility cost estimates will be developed.

The overall goal is to find the coal option which provides the greatest flexibility and least cost for mitigating GHG emissions.

Assessment of Pulverized Coal and CFB boilers

SaskPower is assessing both pulverized coal and CFB options. The goal is to identify the technical and economic differences between pulverized coal and CFB options and their potential for future CO_2 capture. Preliminary lab work has indicated that there may be some advantage in a CFB option due to the inherent SO_2 capture resulting from the alkalinity of Saskatchewan lignite.

CO_2 Capture Plant Integration

A major goal of the current work is to try and determine what provisions are required to allow for the installation of capture plant (currently envisaged to be based on amine solvents) at a later date.

The work can be broken into the following inter-related tasks:

- Review of the flue gas clean up facilities required for a CO_2 capture facility
- Examination of provisions to be made physically to install a CO_2 capture facility on the site at a later date and to provide the necessary services
- Assessment of the scope to optimize overall plant efficiency with a CO_2 capture facility.

Emission Clean-up

SaskPower is conducting a state of the art survey of current emission control technology. This will include a review of vendors and user experience relating to SOx, NOx particulate and mercury control. Based on this review preferred options will be selected by SaskPower. A consultant will then develop capital and operating cost estimates, material balances and layouts

At this time it assumed that a supercritical PC unit will employ a best of class wet scrubber for control of SOx emissions and overfire air for NOx emission control. It is assumed that a CFB unit will employ a polishing process to achieve SOx emissions targets required for an amine CO_2 scrubbing plant. The majority of SOx control will be achieved though capture in the bed.

CO_2 Recovery Facility Placement

SaskPower is conducting a state of the art survey of CO_2 capture technology with leading suppliers. Plant information from suppliers will be used by the consultant to establish preliminary plant layout and service requirements. It is envisaged that the large CO_2 absorber vessel would be located adjacent to the stack. Flue gas would be diverted from the base of the stack into the base of the absorber. A suitable connection point into the stack at the height of the top of the absorber would be incorporated during construction. The reboiler would be sited adjacent to the turbine to minimise both the length of LP steam ducting required and simplify the connections between the CO_2 cooling system and the condensate/feedwater heating system. Lean and rich liquid solvents can be pumped between the two locations.

Thermodynamic integration and performance limits with current capture technology

General principles suggest that the capture plant will be integrated with the main steam cycle principally by:

a) Taking the main steam for the amine reboiler from the IP/LP crossover

b) Using heat recovered from the CO_2 reflux condensers for low temperature condensate heating

c) Using heat from the CO_2 compressor for higher temperature feed water heating – depending on the overall process thermodynamics it may be advantageous to use adiabatic compression instead of intercoolers to increase the available heat temperature.

The economic and thermodynamic performance of power plants designed from the outset for capture probably represents the potential limit for capture ready plant performance. The objective is, as far as possible, to add as little as possible to the additional CO_2 capture cost that would be incurred with a 'built as capture' plant. Starting with recent data from a comprehensive IEA study of post combustion capture [IEA GHG Report PH4/33) and a representative estimate of the cost of electricity for a plant without capture based on a previous study [unpublished CCPC reports] the components for the additional cost of electricity with capture were estimated. The preliminary results are shown in Table 1. It is interesting that, as previously observed in the IEA study, both leading current capture technologies give similar overall results, although with differences in sub-components of the costs. These differences appear to be due to mainly to typical cost/performance tradeoffs in most cases, but the large differences in capital cost were noted by IEA GHG as perhaps needing further examination.

From the figures in Table 1 it appears that optimised capture ready plant is limited to a minimum cost increase of about 27.50 CAD ($ Canadian) when capture is added. Further losses in performance may, however, need to be taken into account. The example shown would occur if steam for solvent regeneration was taken from the IP/LP crossover and the IP exit pressure was maintained by throttling the steam flow upstream of the LP cylinder(s). As Fig. 1 shows, at typical steam abstraction rates the irreversibility due to throttling would reduce the power output by approximately 2%. This is the simplest option for removing the steam, requires no modification to the turbine and would allow the unit to revert to full load operation without capture if required (or to take advantage of improved solvents in the future). Other options, that could give improved efficiency but also would involve additional costs and perhaps reduced flexibility, might include allowing the IP exit pressure to fall (imposing additional loads on the turbine) or rebuilding the LP turbine to take the smaller steam flow (costly, and limiting future flexibility). As Fig. 2 shows, however, LP turbine flow mismatching imposes a relatively small additional penalty on the capture cost and, while optimisation of this aspect of capture ready plant design is very worthwhile, it cannot have major consequences for costs.

More serious uncertainties exist with respect to solvent consumption due to the formation of heat stable salts with SOx and NO_2 in the flue gas. Although advanced FGD plants with single digit ppm SOx concentrations are available they have not been yet been demonstrated in conjunction with amine capture plant. Trials on a range of coals using full scale gas cleanup trains with ultra-high efficiency FGD equipment are urgently needed to establish amine absorber performance. These could take place using any representative PC or CFB plants and do not need to include significant amounts of CO_2 capture; solvent life could be assessed adequately in plants capturing approximately 100 tonne/day of CO_2. It is highly desirable that any gas cleanup problems are debugged at this scale, rather than using full size absorbers. Similarly, new capture plants may wish to commission on cheaper MEA-based solvents and then replace this with more expensive 'designer' solvents when reliable operation has been established.

Future plant performance – avoiding technology 'lock in'

Ideally any type of capture plant should be able to take advantages of the latest advances in capture technology at the time that CO_2 capture is fitted. Post combustion capture appears to be particularly fortunate in this respect, in that none of the capture technology is installed until required. If high efficiency FGD is fitted at the start, however, this might represent a small unnecessary expenditure if future CO_2 capture systems are more tolerant to SOx. Also, if turbine/steam system options are selected that limit the range of steam flows that can abstracted, then it might not be feasible to take advantage of improved solvents. An (upper) limit on the abstraction steam pressure (and hence saturation temperature) is inevitable, however, but this may not be too serious since all water-based solvents being regenerated at atmospheric pressure will probably require heat to be supplied in the range 110-120°C for effective CO_2 stripping.

Conclusions

Normal due diligence considerations now require the impact of a possible future carbon emission pricing to be assessed for any prospective fossil power plant project. The ability to add CO_2 capture places a limit on the financial risk involved and making the plant 'capture ready' reduces this risk limit to the minimum possible value.

No undue obstacles have been identified to making a new lignite power plant in Saskatchewan capture ready. Fortunately a range of options appear to exist for geological storage of the captured CO_2 in the vicinity of the power plant. As a general consideration, it would, however, be advantageous to verify the successful operation of amine solvents in flue gas from coals plants fitted with full scale ultra-high efficiency FGD equipment as soon as possible.

Using current amine technology, adding CO_2 capture to a power plant with an initial electricity cost of 65 CAD/MWh would, at best, add approximately 27.50 CAD/MWh. The corresponding CO_2 value is about 40 CAD/tonne. This assumes that losses and efficiency penalties arising from the reconfiguration of the plant can be avoided, the thrust of the 'capture ready' aspects of the pre feasibility project. The most obvious of these penalties, mismatched flow in the LP turbine, results in an additional cost of approximately 2 CAD/MWh. In practice, capture costs are expected to be reduced in the future due to improvements in this relatively undeveloped application.

To achieve a possible in-service date of 2013, the pre feasibility study is due to be completed later this year to allow decisions to be made on the next stages of a possible project.

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Figure 1 **Effect of throttling to achieve reduced LP steam flow, compared to LP steam turbine sized for steam flow.**

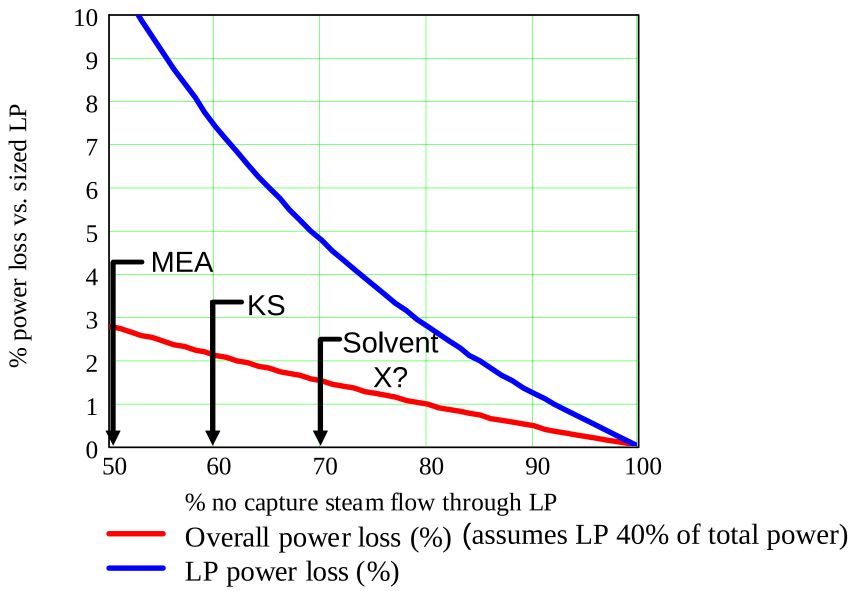

Figure 2 Preliminary breakdown for additional COE with capture

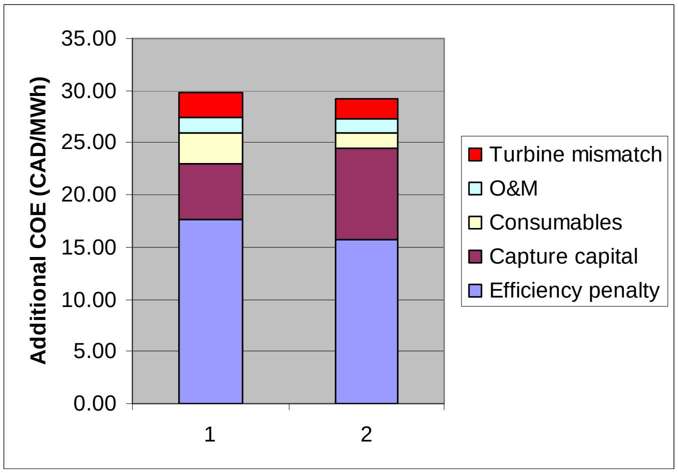

Table 1 Preliminary estimates (in Canadian dollars, CAD) for CO_2 capture costs on a 'built-as-capture' basis and additional losses due to turbine LP cylinder flow mismatching

		Amine 1	Amine 2
Original plant efficiency		43%	43%
Original COE	CAD/MWh_e	65.00	65.00
Efficiency penalty		9.20%	8.40%
Efficiency with capture		33.80%	34.60%
kWth/kWe		2.96	2.89
Efficiency penalty cost	CAD/MWh_e	17.69	15.78
Capture capital cost	CAD/kW_th	120	200
	CAD/kW_e	355.03	578.03
Total cost for 350MW no capture	CAD.M	97.67	162.79
Total cost for 450MW no capture	CAD.M	125.58	209.30
Capture plant life	yr	20.00	20.00
Interest rate		9.25%	9.25%
Annual payment	CAD/kW_e.yr	39.59	64.45
Load factor		85.00%	85.00%
hr on load/yr	hr	7446	7446
Capture plant capital cost	CAD/MWh_e	5.32	8.66
Consumables cost	CAD/MWh_th	1.00	0.50
	CAD/MWh_e	2.96	1.45
O&M cost	CAD/MWh_th	0.50	0.50
	CAD/MWh_e	1.48	1.45
Additional COE	CAD/MWh_e	27.45	27.33
COE with capture	CAD/MWh_e	92.45	92.33
CO2 emissions before capture	kg/kWh_e	0.80	0.80
Emissions with 90% capture	kg/kWh_e	0.10	0.10
CO2 abatement cost	CAD/tonne CO2	39.31	39.01
Turbine mismatch penalty	% of total power	2.50%	2%
Approximate value of lost power	CAD/MWh_e	2.37	1.88